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Evaluation of the Technological Feasibility, and Cost of Selected Control Alternatives Necessary to Meet the Proposed Ohio SO2 Regulations for Industrial Boilers and Processes. Volume VI. Mead Corporation Chillicothe Mill

GCA Corp, Bedford, Mass. GCA Technology Div.

Prepared for

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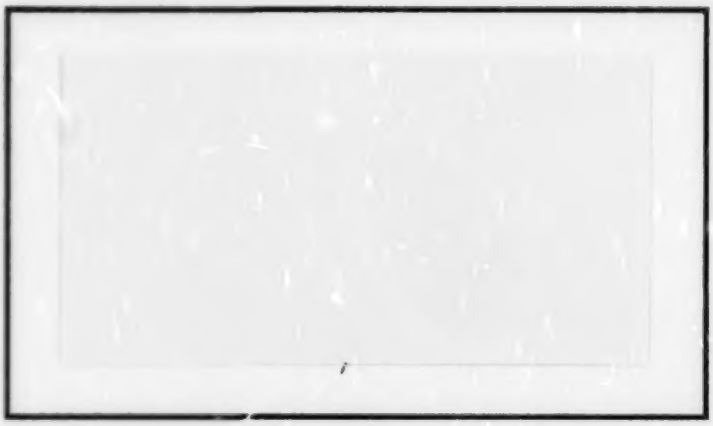

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EVALUATION OF THE TECHNOLOGICAL FEASIBILITY, AND COST OF SELECTED CONTROL ALTERNATIVES NECESSARY TO MEET THE PROPOSED OHIO SO_2 REGULATIONS FOR INDUSTRIAL BOILERS AND PROCESSES

FINAL REPORT

Contract No. 68-01-3155
Task Order No. 4

August 1976

Volume VI

MEAD CORPORATION

CHILLICOTHE MILL

by

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16. ABSTRACT
This report presents an evaluation by the GCA Corporation, GCA/Technology Division, of technological feasibility and cost of complying with the proposed Ohio sulfur dioxide regulation (40 FR 52410, November 10, 1975) at the Mead Corporation's Chillicothe Mill. The final USEPA Sulfur Dioxide Control Strategy for the State of Ohio Technical Support Documents, Vol. I and II, (EPA 905/2-76-002) may be obtained from NTIS.

This facility operates three coal-fired boilers to provide process steam for the production of paper. After collecting necessary site and process specific data by means of a plant visit, the technical feasibility and cost of a lime-based desulfurization system were evaluated.

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ABSTRACT

The results of an evaluation of the technical feasibility and cost of complying with the proposed SO_2 emission regulation for fossil fuel-fired steam generators at Mead Corporation's Chillicothe Mill are presented in this report. The site was selected for study as a facility exemplifying the control requirements for medium size industrial boilers subject to an SO_2 emission limit of 5 to 6 lb $SO_2/10^6$ Btu fuel input. The technical feasibility and cost of a lime scrubbing system was determined. In addition the present cost of compliance coal was evaluated.

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SECTION I

SUMMARY AND CONCLUSIONS

Mead Corporation's Chillicothe Mill operates three coal-fired boilers to provide process steam for the production of paper. During 1975, 246,000 tons of 4.3 percent sulfur coal were burned producing 20,000 tons of SO_2. An evaluation was made of the technical feasibility of reducing SO_2 emission to 5.2 $lb/10^6$ Btu (a 30 percent reduction) as would be required by the proposed regulation.

Flue gas desulfurization by lime, limestone, Wellman-Lord and double alkali scrubbing were considered. A 114,000 scfm, 90 percent efficient desulfurization system would be required to meet the proposed SO_2 emission limits at Mead. Since limestone desulfurization systems smaller than 130,000 scfm are not currently commercially marketed, cost data for these systems were not available. Manufacturers of lime, Wellman-Lord and double alkali scrubbing systems were contacted to obtain cost estimates. However, only lime-based desulfurization system costs were provided by equipment vendors within the time frame of this project.

The total capital requirement for the lime based system including the battery limit plant, site preparation, retrofit requirement and working capital was $4.44 million. Total annualized cost including cost of capital, depreciation, federal income tax, operating cost and solid waste disposal was $1.6 million. This cost is equivalent to $0.195/lb sulfur removed or $0.22/$10^6$ Btu input. The present incremental cost of purchasing and blending low sulfur coal with the present coal to comply with the proposed SO_2

emission regulations was estimated to range from \$0.23 to \$0.28/10^6 Btu. The potential increment cost of mechanically cleaned compliance coal was estimated to be \$0.08 to \$0.15/10^6 Btu.

SECTION II

PROCESS AND SITE DESCRIPTION

Mead Corporation's Chillicothe Mill was visited on 13 April 1976. This paper manufacturing facility is located in Chillicothe, Ohio which is in Ross County. During 1975, 245,954 tons of coal averaging 4.28 percent sulfur (on a monthly basis) were used to generate the steam necessary for the production of paper. The purpose of the plant visit was to collect site and process specific data necessary to determine the technical feasibility and cost of complying with the proposed regulation for control of SO_2 emissions from coal-fired boilers. Mr. Russ Kross, Director of Environment and Energy and Mr. Will Lapp, Manager of Environmental Controls represented Mead. Boiler design and operating data along with boilerhouse and site layout diagrams were provided by Mead.

The Chillicothe Mill boiler facility consists of three pulverized dry bottom boilers (Nos. 5, 7, 8) which were installed in 1954, 1963 and 1972, respectively. Units 5 and 8 are front wall-fired while unit no. 7 is tangentially-fired. Mead estimates that the remaining life of these boilers is 20 years.

At the present time the particulate emissions from each of these boilers are controlled by a mechanical collector. Two electrostaitc precipitators (units no. 1 and 2) that will be put in series with the existing mechanical collectors are being constructed and are scheduled to be operational by the fall of 1976. One of these precipitators will handle the flue gas from boiler no. 8 while the other will handle the combined flue gas flow from boiler nos. 5 and 7. The clean flue gas leaving these precipitators will

be combined and vented to a 475 foot stack. The flue gas from two distillate oil-fired power boilers which are scheduled for start-up in the fall of 1978 will also be vented to the stack. Ross County is in the Wilmington-Chillicothe-Logan Intrastate Air Quality Control Region (AQCR 182) which is a Priority III Region for particulates. The boilers at Mead, with a combined rated capacity of 1207 x 10^6 Btu/hr input are limited by the regulations to 0.15 lb particulate/10^6 Btu input. The installation of the electrostatic precipitators will reduce the particulate emission rate from Mead's boilers to 0.07 lb particulate/10^6 Btu input which is well in compliance with the regulations.

The bottom ash generated by the three dry bottom pulverized coal-fired boilers is sluiced with water. The resulting sludge is sent to a wastewater treatment plant where it, along with other process slurries, is clarified. The dewatered underflow sludge from the clarifier is hauled away by truck to a landfill. The fly ash collected by the existing mechanical collectors and the nearly completed electrostatic precipitators is handled dry. This fly ash is ash is trucked away to a second landfill. Both of the aforementioned landfills are approximately 10 miles from the plant site.

Table 1 presents pertinent design and operating data for the boilers at Mead. Barring unscheduled outages, Mead operates their boilers 24 hour/day, 350 days/year. Based on monthly averages, Table 2 presents coal sulfur and ash contents, heating values and consumption rates for the years 1974 and 1975.

Mead purchases their coal from mines located in Vinton and Jackson Counties, Ohio. The coal costs approximately $16.5/ton which includes delivery by truck.

According to the proposed regulation S52.1881(b)(2) the allowable SO_2 emission rate for fossil fuel-fired steam generators in Ross County is 5.2 lb SO_2/10^6 Btu input.[1]

Table 1. MEAD BOILER DESIGN AND OPERATING DATA

	Pulverized dry bottom		
	No. 5	No. 7	No. 8
Rated capacity,			
10^6 Btu/hr input	320	407	480
lb coal/hr	27,800	35,400	41,700
Normal operating rate,			
10^6 Btu/hr input	320	407	480
lb coal/hr	27,800	35,400	41,700
Stack gas temperature, ^oF	330	330	330
Stack gas flow at rated capacity scfm	88,480	112,545	132,730
Stack gas flow at normal operating rate, scfm	88,480	112,545	132,730
Excess air, percent	19 - 58	19 - 58	19 - 58
SO_2 concentration stack gas, ppm[a]	2,760	2,760	2,760
SO_2 emission rate lb $SO_2/10^6$ Btu input[a]	7.45	7.45	7.45
Allowable SO_2 emission rate, lb $SO_2/10^6$ Btu input	5.20	5.20	5.20

[a]These values were calculated using the average coal sulfur content and heating value for 1975 and the assumption that 100 percent of the sulfur in the coal is converted to SO_2.

Table 2. COAL DATA FOR 1974 AND 1975 BASED ON MONTHLY AVERAGES

	1974	1975
Sulfur content, %		
average	4.4	4.3
range	3.7 - 4.8	3.9 - 4.9
Ash content, %		
average	21.0	18.8
range	17.3 - 25.1	15.7 - 22.8
Heating value, Btu/lb		
average	11,191	11,546
range	10,573 - 12,240	10,753 - 12,209
Annual consumption, ton/yr	300,600	245,954

During 1975, the average sulfur content and heating value of the coal combusted at Mead were 4.3 percent and 11,346 Btu/lb respectively. Assuming 100 percent of the sulfur in the coal is converted to SO_2, this corresponds to a 1975 emission rate of 7.45 lb $SO_2/10^6$ Btu input. To meet the proposed limits, the 1975 emissions would have to be reduced by 30 percent.

Figure 1 presents a schematic of the Mead boiler site. As illustrated by this figure, there are approximately 13,000 square feet of available open area adjacent to the boilers and electrostatic precipitators that could serve as a site for a flue gas desulfurization system. As shown by the vertical diagram of Meads' No. 1 electrostatic precipitator (see Figure 2), retrofitting a desulfurization system to the pulverized coal-fired boilers should not present any unusual problems. The vertical diagram for the No. 2 electrostatic precipitator is nearly identical to that of the No. 1 precipitator. Both precipitators share a common duct to the stack.

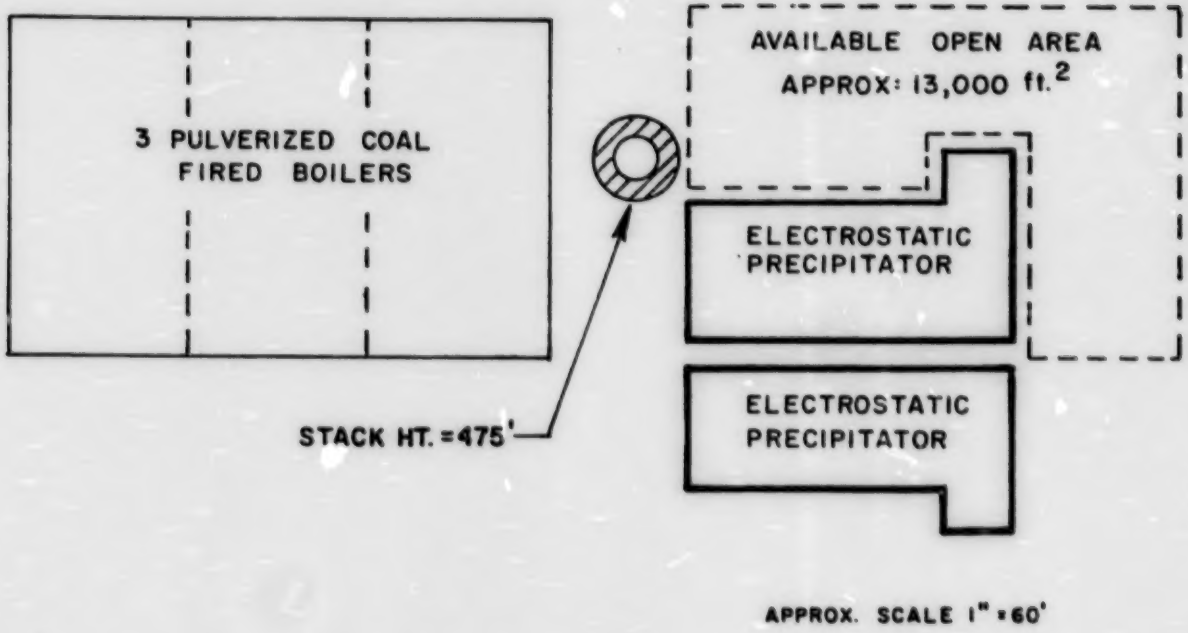

Figure 1. Mead boiler site

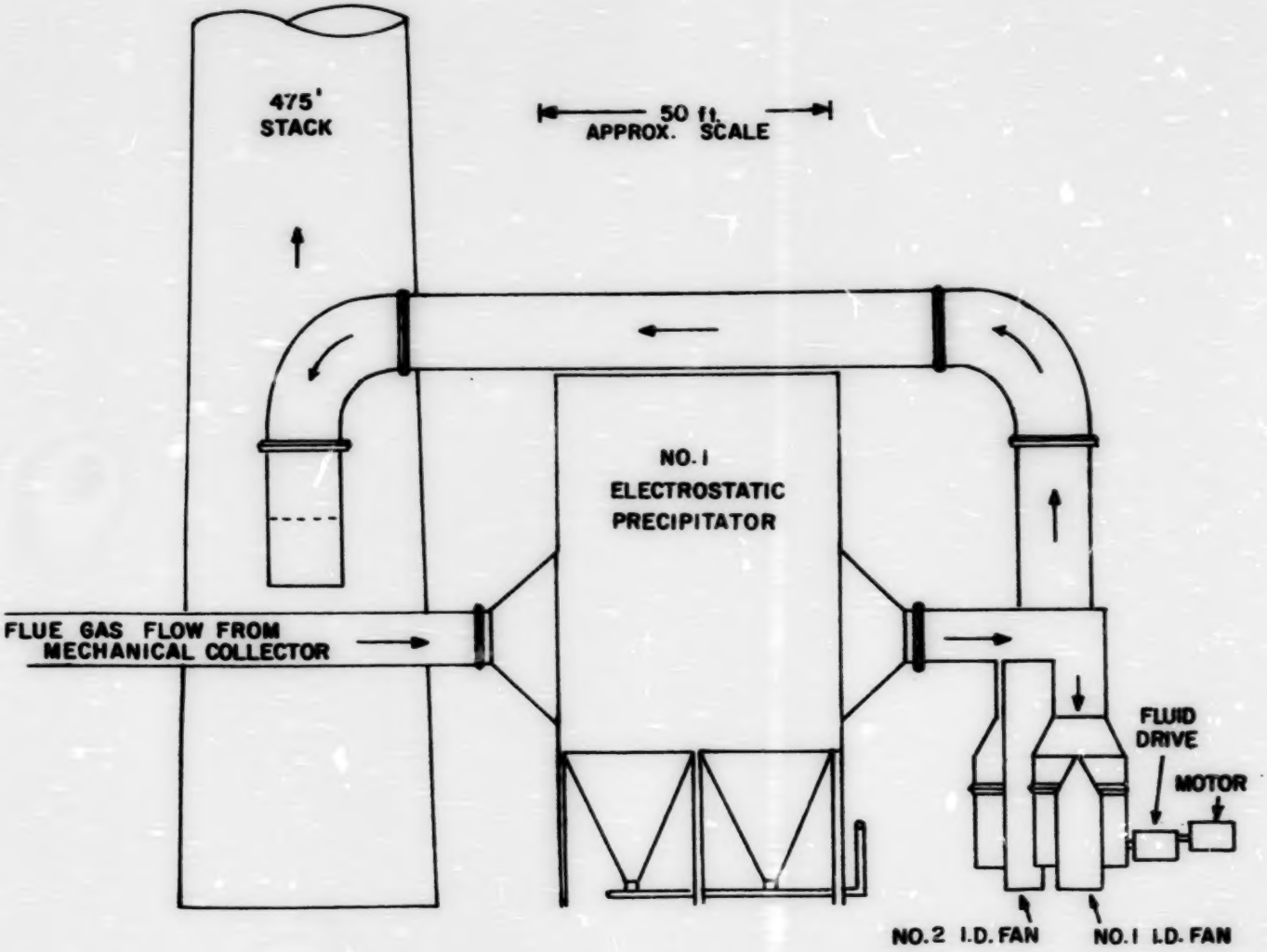

Figure 2. Vertical diagram of Mead No. 1 electrostatic precipitator

SECTION III

SO_2 CONTROL TECHNOLOGY FOR COAL-FIRED BOILERS

FLUE GAS DESULFURIZATION SYSTEMS

Based on our reveiw of flue gas desulfurization systems the following SO_2 scrubber systems were selected for evaluation of their potential applicability to the coal-fired industrial boilers at the Mead Corporation:

1. Lime (CaO) and limestone ($CaCO_3$)
2. Double alkali (NaOH/CaO)
3. Wellman-Lord (Na_2SO_3)

Selection was based primarily on full scale operating experience. The SO_2 removal efficiencies that have been demonstrated by these flue gas desulfurization systems are high enough to put Mead's coal-fired boilers well in compliance with the proposed SO_2 emission regulations.

Lime and Limestone Scrubber Systems

Combustion Engineering,* Research-Cottrell+ and many other companies commercially manufacture lime and limestone scrubbing systems. In these systems, lime or limestone reacts with SO_2 and SO_3 in the flue

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*C-E Power Systems, Combustion Engineering, Inc., 1000 Prospect Hill Windsor, Conn.

+Research-Cottrell, P.O. Box 750, Bound Brook, N.J.

gas to form calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$). The Combustion Engineering system introduces the additive, a slurry of pulverized limestone or slaked lime, directly into the scrubber. Recirculation pumps convey the scrubbing solution from the scrubber bottom to underbed spray nozzles. The incoming gas, laden with dust and SO_2, contacts the sprayed slurry and continues to the marble beds. The solution then drains to the scrubber bottom where the chemical reaction is completed and solids are precipitated. A bleed line provides for solids removal to a clarifier or pond. Here the solids settle and the clarified water is recirculated. The clean flue gas passes through a mist eliminator in order to remove moisture and then may be reheated in order to protect the fan and reduce the visibility of the stack plume.[2] A schematic diagram of the C-E lime/limestone scrubber system is presented in Figure 3.

Research-Cottrell offers both a limestone and a lime (Bahco) scrubber system. The limestone scrubber system consists of two stages (see Figure 4). In the first stage, a flooded disc wet scrubber removes fly ash and since a limestone slurry is used to control the pH at this stage, approximately 20 percent of the SO_2 in the flue gas is removed as well. This first stage also acts as a quencher, saturating the gas to a temperature of 125°F. A controlled amount of ash-laden slurry discharges from this first stage to a holding tank for final disposal on an intermittent basis. In the second stage, the flue gas passes up through the packing of the absorber tower, where the limestone slurry circulates. The corrugated polypropylene packing has a large surface area, designed to insure maximum contact between the SO_2 and the limestone slurry. The spent slurry, which includes unreacted limestone, flows into an absorber tank, where salts precipitate out. The reusable slurry, augmented by additional limestone and makeup water, then recirculates through the system. A controlled amount of the slurry is bled to the wet scrubber stage for pH control. After

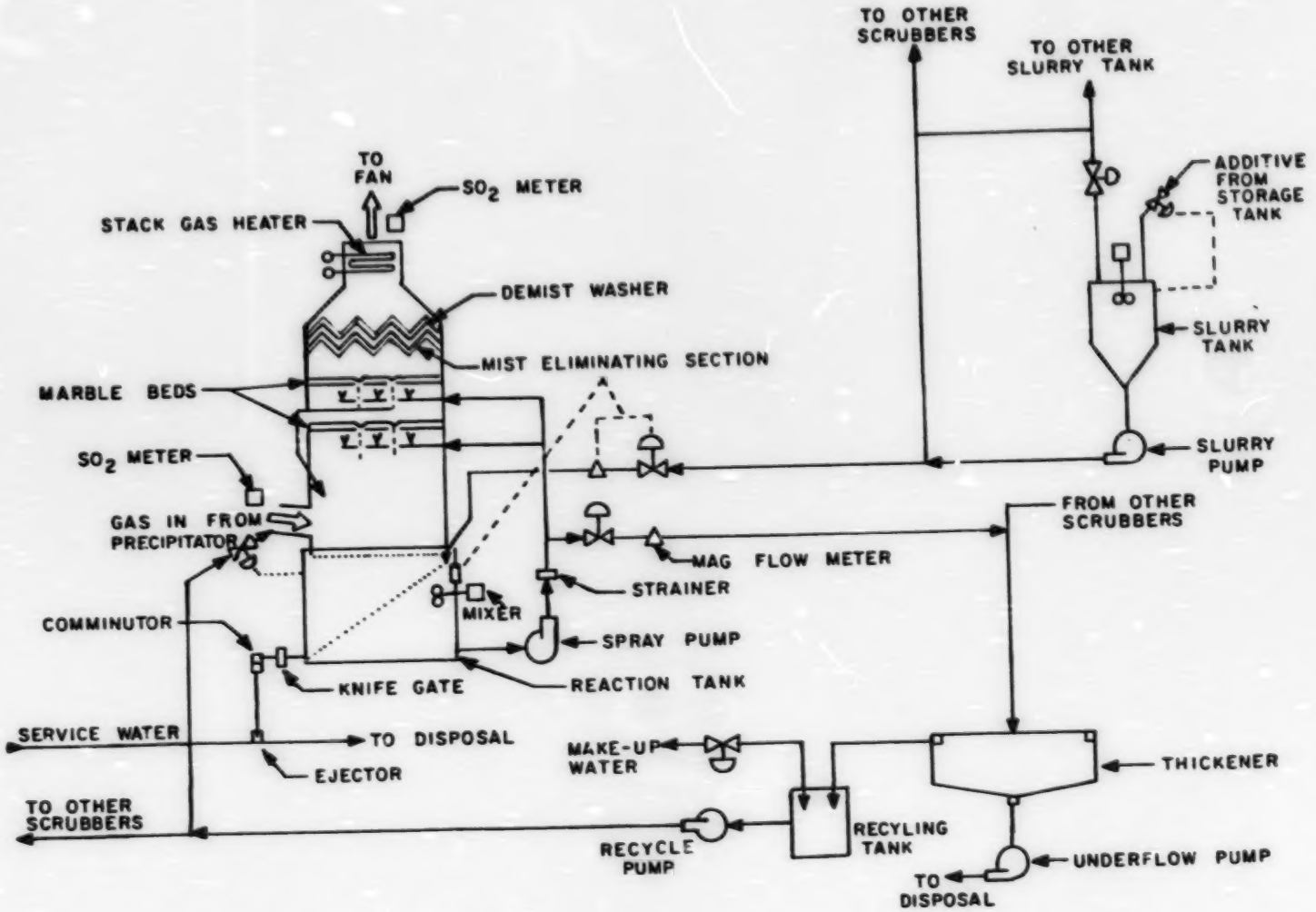


Figure 3. C-E lime/limestone scrubber system[3]

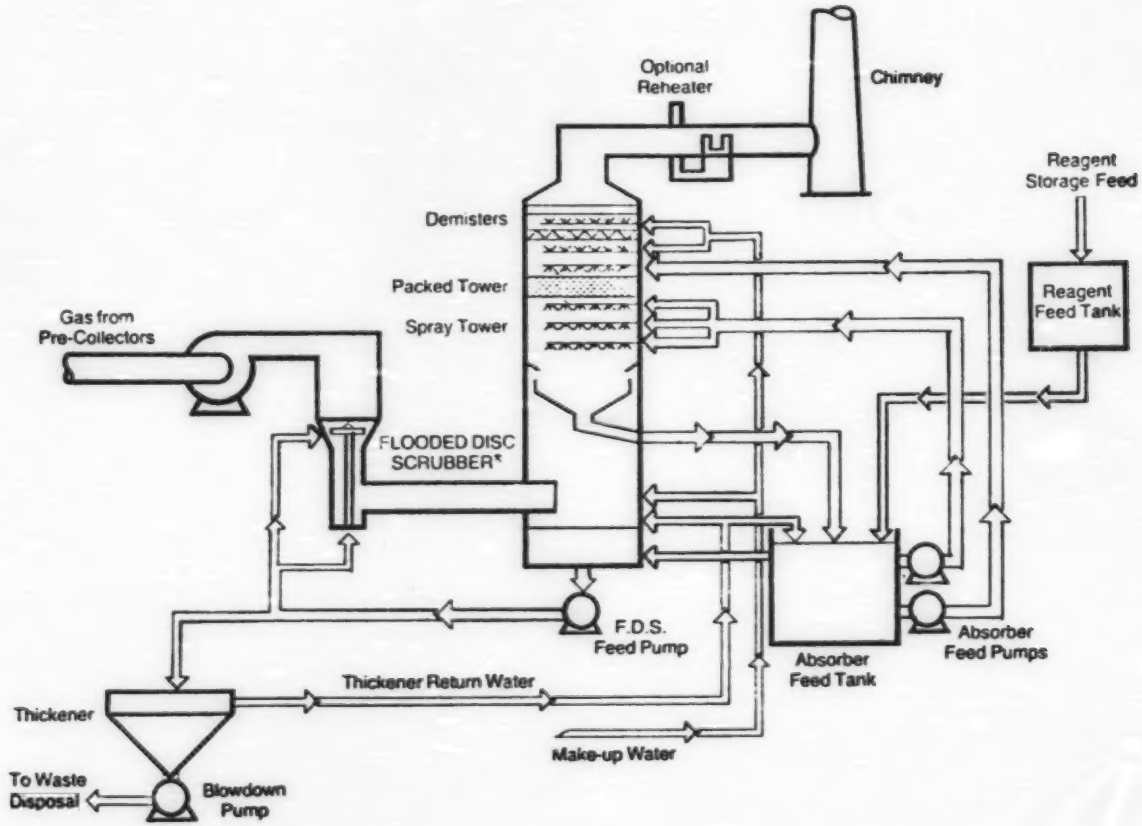


Figure 4. R-C limestone scrubber system[5]

the absorber tower, the flue gas passes through mechanical mist eliminators and then a reheater. Reheating the flue gas prevents stack corrosion, avoids acid rain around the plant, and improves plume buoyancy.[4]

The Research-Cottrell lime (Bahco) scrubbing system (see Figure 5) consists of a two stage venturi. At the bottom of the column, flue gas is directed down against the surface of a milk of lime slurry. The high velocity gas-liquid contact produces a vigorous cascade of droplets that carry up into the first scrubber stage for turbulent mixing with the flue gas. Above the first venturi, droplets are separated in an inertial collector while the gas continues to a second stage. Here the gas-liquid contact process is repeated. A mist eliminator above the second stage frees the gas of droplets prior to exiting out the stack. Separated liquids from both stages of the venturi return to the lower impingement zone. A fraction of this return flow is continuously removed for disposal, usually to a thickener. Clarified liquid is returned to the lime dissolving tank to minimize makeup requirements.[6]

Limestone and lime based scrubbing is the oldest and most widely used commercially available flue gas desulfurization technology. As shown in Table 3, limestone scrubbing units applied to coal-fired boilers have been operating since 1968. As would be expected, the availability of the early units was not good. However, since then the technology has improved due to operating and design experience. As a result, the availability of lime and limestone scrubbing systems installed since 1973 has thus far ranged from 58 to 90 percent, averaging over the operating life of the systems.[7,8] It is important to note that specific units such as the Cholla No. 1 have been able to achieve availability of 90 to 100 percent over the last 2 years.[7]

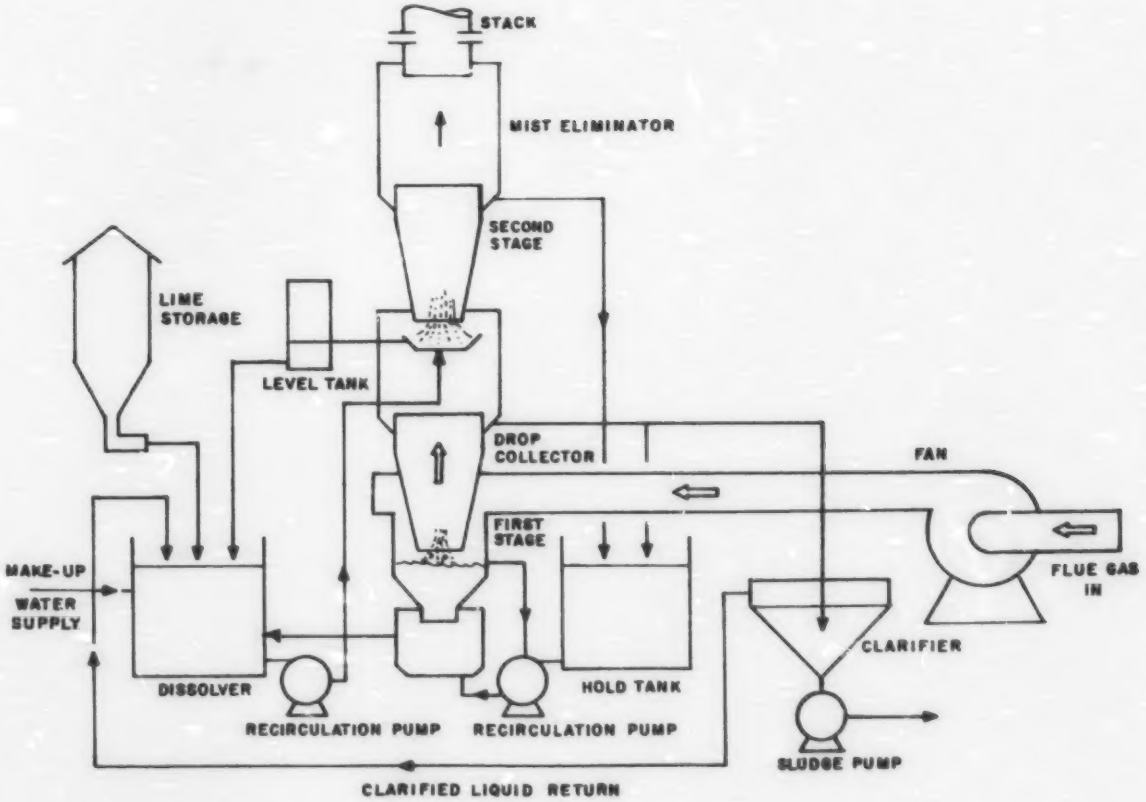


Figure 5. R-C lime (Bahco) scrubber system[6]

Table 3. STATUS OF LIME AND LIMESTONE FLUE GAS DESULFURIZATION SYSTEMS AS OF 5/76[7,8]

Operational systems

Utility company power station	Size of FGD unit, MW[a]	Vendor/process	Fuel characteristics	Startup date, mo/yr	Availability, %
Arizona Public Service Cholla No. 1	115	Research Cottrell/ limestone scrubbing	Coal - 0.44-1 percent sulfur	10/73	88
Commonwealth Edison Will County No. 1	167	Babcock & Wilcox/ limestone scrubbing	Coal - 9463 Btu, 2.1 percent sulfur	2/72	26
Dairyland Power Coop Alma Station	80	Foster Wheeler/ lime injection	Coal - 3.0 - 3.5 percent sulfur	6/71	-
Duquesne Light Elrama	510	Chemico/ lime scrubbing	Coal - 1.0 - 2.8 percent sulfur	10/75	-
Duquesne Light Phillips	410	Chemico/ lime scrubbing	Coal - 1.0 - 2.8 percent sulfur	7/73	73
Kansas City Power & Light Hawthorn No. 3	140	Combustion Engineering/ limestone injection & wet scrub	Coal - 0.6 - 3.0 percent sulfur	11/72	36
Kansas City Power & Light La Cygne No. 1	820	Babcock & Wilcox/ limestone scrubbing	Coal - 5.2 percent sulfur	2/73	85
Kansas City Power & Light Hawthorn No. 4	100	Combustion Engineering limestone injection & wet scrub	Coal - 0.6 - 3.0 percent sulfur	8/72	64
Kansas Power & Light Lawrence No. 4	125	Combustion Engineering/ limestone injection & wet scrub	Coal - 3.5 percent sulfur	12/68	-
Kansas Power & Light Lawrence No. 5	400	Combustion Engineering limestone injection & wet scrub	Coal - 0.5 percent sulfur	11/71	-
Kentucky Utilities Green River - Units 1 & 2	64	American Air Filter/ lime scrubbing	Coal - 3.8 percent sulfur	10/75	-
Louisville Gas & Electric Paddys Run No. 6	65	Combustion Engineering/ lime scrubbing	Coal - 3.5 - 4.0 percent sulfur	4/73	58
Montana Power Co. Colstrip No. 1	360	Combustion Equip. Associates/ lime scrubbing	Coal - 0.8 percent sulfur	10/75	-
Rickenbacker AFB Rickenbacker	42	Research Cottrell/ lime scrubbing	Coal - 3.6 percent sulfur	3/76	90
Pennsylvania Power Co. Bruce Mansfield No. 1	835	Chemico/ lime scrubbing	Coal - 4.3 percent sulfur	10/75	8
Public Service Co. of Colorado - Valmont No. 5	50	Universal Oil Products/ limestone scrubbing	Coal - 0.72 percent sulfur	1/75	-
Southern California Edison Mohave No. 1A	170	Universal Oil Products/ limestone scrubbing	Coal - 0.5 - 0.8 percent sulfur	11/74	62
Tennessee Valley Authority Shawnee No. 10	30	Tennessee Valley Authority/ lime/limestone scrubbing	Coal - 2.9 percent sulfur	4/72	-
Northern States Power Co. Sherburne No. 1	680	Combustion Engineering/ limestone scrubbing	Coal - 0.8 percent sulfur	3/76	-
Arizona Public Service Four Corners No. 5A	160	SCE/lime scrubbing	Coal - 0.7 percent sulfur	2/76	-

[a]One MW is approximately equivalent to 10 x 10^6 Btu/hr fuel input and 2200 scfm flue gas.

Table 3 (continued). STATUS OF LIME AND LIMESTONE FLUE GAS DESULFURIZATION SYSTEMS AS OF 5/76[7,8]

Systems under construction

Utility company power station	Size of FGD unit, MW	Vendor/process	Fuel characteristics	Startup date, mo/yr	Availability, %
Central Illinois Light Co. Duck Creek No. 1	100	Riley Stoker/Environeering/ limestone scrubbing	Coal - 2.5 - 3.0 percent sulfur	6/76	-
Columbus & Southern Ohio Elec. - Conesville No. 5	400	Universal Oil Products/ lime scrubbing	Coal - 4.5 - 4.9 percent sulfur	6/76	-
Detroit Edison St. Clair No. 6	180	Peabody Engineering/ limestone scrubbing	Coal - 3.7 percent sulfur	5/76	-
Indianapolis Power & Light Co. - Petersburg No. 3	530	Universal Oil Products/ limestone scrubbing	Coal - 3.0 - 3.5 percent sulfur	9/77	-
Louisville Gas & Electric Cane Run No. 4	178	American Air Filter/ lime scrubbing	Coal - 3.5 - 4.05 percent sulfur	6/76	-
Louisville Gas & Electric Can Run No. 5	183	Combustion Engineering/ lime scrubbing	Coal - 3.5 - 4.05 percent sulfur	12/77	-
Louisville Gas & Electric Mill Creek No. 3	425	American Air Filter/ lime scrubbing	Coal - 3.5 - 4.0 percent sulfur	7/77	-
Minnkota Power Cooperative Milton R. Young No. 2	450	Combustion Equip. Associates/ limestone scrubbing	Lignite - 6,500 Btu, 0.7 percent S	8/77	-
Montana Power Co. Colstrip No. 2	360	Combustion Equip. Associates/ lime scrubbing	Coal - 0.8 percent sulfur	7/76	-
Northern States Power Co. Sherburne No. 2	680	Combustion Engineering/ limestone scrubbing	Coal - 0.8 percent sulfur	5/77	-
Pennsylvania Power Co. Bruce Mansfield No. 2	835	Chemico/ lime scrubbing	Coal - 4.3 percent sulfur	4/77	-
Springfield City Utilities Southwest No. 1	200	Universal Oil Products/ limestone scrubbing	Coal - 3.5 percent sulfur	8/76	-
Tennessee Valley Authority Widows Creek No. 8	550	Tennessee Valley Authority/ limestone scrubbing	Coal - 3.7 percent sulfur	2/77	-
Texas Utilities Co. Martin Lake No. 1	793	Research Cottrell/ limestone scrubbing	Coal - 1.0 percent sulfur	1/77	-
Texas Utilities Co. Martin Lake No. 2	793	Research Cottrell/ limestone scrubbing	Coal - 1.0 percent sulfur	10/77	-
Utah Power & Light Co. Huntington No. 1	415	Chemico/ lime scrubbing	Coal - 0.5 percent sulfur	6/77	-

Table 3 (continued). STATUS OF LIME AND LIMESTONE FLUE GAS DESULFURIZATION SYSTEMS AS OF 5/76[7,8]

Contracts awarded - engineering design phase of development

Utility company power station	Size of FGD unit, MW	Vendor/process	Fuel characteristics	Startup date, mo/yr	Availability, %
Columbus & Southern Ohio Elec. - Conesville No. 6	400	Universal Oil Products/ lime scrubbing	Coal - 4.5 - 4.9 percent sulfur	1/78	-
Arizona Public Service Cholla No. 2	250	Research Cottrell/ limestone scrubbing	Coal - 0.44 - 1 percent sulfur	6/77	-
Alabama Electric Coop Tombigbee No. 2	225	Peabody Engineering/ limestone scrubbing	Coal - 0.8 - 1.5 percent sulfur	3/78	-
Alabama Electric Coop Tombigbee No. 1	225	Peabody Engineering/ limestone scrubbing	Coal - 0.8 - 1.5 percent sulfur	3/79	-
S. Mississippi Elec. PWR Assoc. - R.D. Morrow No. 2	180	Riley Stoker/Environeering/ limestone scrubbing	Coal - 1 percent sulfur	6/78	-
S. Mississippi Elec. PWR Assoc. - R.D. Morrow No. 1	180	Riley Stoker/Environeering/ limestone scrubbing	Coal - 1 percent sulfur	11/77	-
Arizona Electric Power Coop Apache No. 2	200	Research Cottrell/ limestone scrubbing	Coal - 0.5 - 0.8 percent sulfur	6/79	-
Arizona Electric Power Coop Apache No. 3	205	Research Cottrell/ limestone scrubbing	Coal - 0.5 - 0.8 percent sulfur	6/79	-
S. Carolina Pub Serv Authority - Winyah No. 2	140	Babcock & Wilcox/ limestone scrubbing	Coal - 1.0 percent sulfur	5/77	-
Brazos Electric Power Coop G & T Cooperative Project No. 1	400	Babcock & Wilcox/ limestone scrubbing	Coal - 1.67 percent sulfur	12/79	-
Commonwealth Edison Powerton No. 51	425	Universal Oil Products/ limestone scrubbing	Coal - 3.6 percent sulfur	12/79	-
Allegheny Power System Pleasants No. 1	625	Babcock & Wilcox/ lime scrubbing	Coal - 2.0 - 5.0 percent sulfur	3/79	-
Allegheny Power System Pleasants No. 2	625	Babcock & Wilcox/ lime scrubbing	Coal - 2.0 - 5.0 percent sulfur	3/80	-
Kansas Power & Light Jeffery No. 2	680	Combustion Engineering/ limestone scrubbing	Coal - 0.32 percent sulfur	6/79	-
Louisville Gas & Electric Mill Creek No. 4	425	American Air Filter/ lime scrubbing	Coal - 3.5 - 4.0 percent sulfur	7/79	-
Pennsylvania Power Co. Bruce Mansfield No. 3	835	Pullman Kellogg/ limestone scrubbing	Coal - 4.3 percent sulfur	4/79	-
Kansas Power & Light Jeffery No. 1	680	Combustion Engineering/ limestone scrubbing	Coal - 0.32 percent sulfur	6/78	-
Utah Power & Light Co. Emery No. 1	400	Chemico/ lime scrubbing	Coal - 0.5 percent sulfur	6/78	-
Southern Illinois Power Coop Southern Illinois Power Pt. 4	184	Babcock & Wilcox/ limestone scrubbing	Coal -	1/78	-

Tables 4, 5 and 6 present pertinent design and operating data for the limestone and lime based scrubbing systems discussed in this section. As Tables 4 and 5 show that limestone based scrubbing system are not commercially available for flue gas flows less than 130,000 scfm. Because the gas flow requiring desulfurization at Mead is only 113,000 scfm, the Combustion Engineering and Research-Cottrell limestone scrubbing systems would not be applicable. However, the Bahco lime based scrubbing system is commercially available in this size range.

Double Alkali Scrubber Systems

FMC Corporation* commercially offers double alkali scrubber systems. The process involves a sodium-based scrubbing loop in which the sulfur dioxide in flue gas is collected according to the following reactions:

$$Na_2CO_3 + H_2O \rightarrow 2NaOH + CO_2$$

$$2NaOH + SO_2 \rightarrow Na_2SO_3 + H_2O$$

$$Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3$$

and subsequently precipitated with calcium in a separate loop according to the reaction

$$2NaHSO_3 + Ca(OH)_2 \rightarrow CaSO_3 + Na_2SO_3 + 2H_2O$$

This system was developed primarily to alleviate scaling problems initially encountered with lime/limestone systems. The spent scrubber solution which is primarily composed of sodium bisulfite ($NaHSO_3$) is pumped to a lime reactor where it mixed with slaked lime. In the reactor, sodium bisulfite is converted to sodium sulfite (Na_2SO_3) and calcium sulfite

* FMC Corporation, Environmental Equipment Division, 21 Charles Street, Westport, Conn.

Table 4. COMBUSTION ENGINEERING LIME/LIMESTONE SCRUBBING SYSTEM[9,10]

Smallest system capacity commercially available (scfm)	130,000
Overall pressure drop through system (in H_2O)	10 - 16
Turndown ratio of system	3:1
SO_2 removal efficiency, percent	75 - 90
Raw materials	Limestone or lime
By-products	None
Wastes,[a] lb waste/lb SO_2 removed	6.9 lb sludge cake from clarifier containing 35 percent solids ($CaSO_3$, $CaSO_4$ and unreacted limestone) and 65 percent water
Maintenance presented some problems	Scale and solids buildup and corrosion have presented some problems which have been alleviated by modifying the system design.
Development status (see Table 3)	Operational systems 140 Mw 0.6 - 3.0 % S coal 140 Mw 0.6 - 3.0 % S coal 125 Mw 3.5 % S coal 400 Mw 0.5 % S coal 65 Mw 3.5 - 4.0 % S coal 360 Mw 0.8 % S coal Systems under construction 183 Mw 3.5 - 4.05 % S coal 680 Mw 0.8 % S coal 680 Mw 0.8 % S coal

[a]Does not include the fly ash that would be removed.

Table 5. RESEARCH-COTTRELL LIMESTONE SCRUBBING SYSTEM[5,7,8,11]

Smallest system capacity commercially available (scfm)	130,000
Overall pressure drop through system (in H_2O)	10 - 20
Turndown ratio of system	4:1
SO_2 removal efficiency, percent	85 - 90
Raw materials	Limestone (95 percent $CaCO_3$)
By-products	None
Wastes[a] lb waste/lb SO_2 removed	6.9 lb sludge cake from clarifier containing 35 percent solids ($CaSO_3$, $CaSO_4$ and unreacted limestone) and 65 percent water
Maintenance	Scale and solids buildup and corrosion have presented some problems which have been alleviated by modifying the system design.
Development status (see Table 3)	Operational systems 115 Mw 0.44 - 1.0 % S coal Systems under construction or in the design stage of development 250 Mw 0.44 - 1.0 % S coal 793 Mw 1.0 % S coal 793 Mw 1.0 % S coal

[a]Does not include the fly ash that would be removed.

Table 6. RESEARCH COTTRELL LIME (BAHCO) SCRUBBING SYSTEM[12]

Smallest system capacity commercially available (scfm)	20,000
Overall pressure drop through system (in H_2O)	16 - 26
Turndown ratio of system[a]	1.5 - 1
SO_2 removal efficiency, percent	90 - 99
Raw materials	Lime
By-products	None
wastes[b] lb waste/lb SO_2 removed	6.1 lb cake containing 35 percent solids ($CaSO_3$ and $CaSO_4$) and 65 percent water
Maintenance	Scaling and solids deposition appear to be less severe than for limestone based scrubbing systems. Corrosion can be minimized by properly designing the system.
Development status (see Table 3)	Operational systems 42 Mw 3.6 % S coal

[a]Any turndown ratio may be accomodated by the addition of makeup air.

[b]Does not include the fly ash that would be removed.

($CaSO_3$) is precipitated out, thickened and put through a rotary drum vacuum filter. The sodium sulfite solution is then recirculated back to the scrubber. Due to oxygen in the flue gas, a portion of the sodium sulfite is oxidized to sodium sulfate. These chemical losses are offset with makeup soda ash.[13] A schematic of FMC's double alkali scrubber system is presented in Figure 6. Table 7 presents pertinent design and operating data for the FMC double alkali scrubbing system.

Wellman-Lord SO_2 Recovery Process

The Wellman-Lord regenerative SO_2 process is commercially marketed by Davy Powergas.* In this process flue gas is contacted counter-currently with a sodium sulfite (Na_2SO_3) solution in a trayed or packed absorber. SO_2 in the flue gas combines chemically with sodium sulfite to form sodium bisulfite ($NaHSO_3$). Due to oxygen in the flue gas, a portion of the sodium sulfite is oxidized to sodium sulfate. The bisulfite rich sodium-salt solution discharged from the absorber is thermally regenerated in a forced circulation evaporator. During the thermal regeneration of sodium bisulfite, SO_2 is liberated and sodium sulfite is reformed. The sulfur dioxide along with the equilibrium water vapor pass overhead through a series of parallel condensers where the desired level of SO_2 purity is achieved. The water condensate is returned to the process. Sulfur dioxide can be concentrated to greater than 95 percent. This recovered SO_2 can be converted to liquid SO_2 sulfuric acid or elemental sulfur.[15,16] For industrial size boilers, the economics of converting recovered SO_2 to sulfuric acid or elemental sulfur are unfavorable unless a plant already exists on the site. However, for industrial size boiler installations, production of liquid SO_2 appears to be a viable alternative.[17] To produce liquid SO_2, the SO_2 gas is first dried with silica gel. The dry SO_2 gas is then compressed and condensed. The liquid SO_2 is collected in a pressurized

*Davy Powergas, Inc. P.O. Box 2436, Lakeland, Florida 33803.

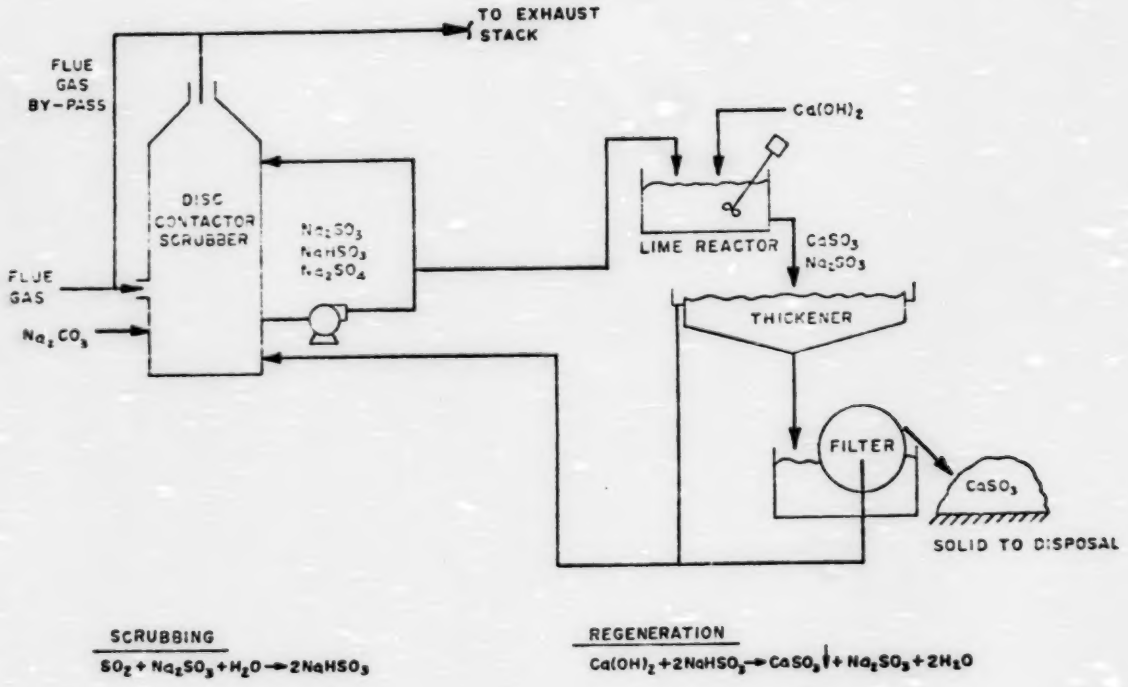


Figure 6. FMC double alkali scrubber system[13]

Table 7. FMC DOUBLE ALKALI SCRUBBING SYSTEM[14]

Smallest system capacity commercially available (scfm)	33,000
Overall pressure drop through system (in H_2O)	5 - 15
Turndown ratio of system	4:1
SO_2 removal efficiency, percent	90 - 95
Raw materials	Lime (CaO), soda ash (Na_2CO_3)
By-products	None
Wastes[a] lb waste/lb SO_2 removed	5.8 lb sludge cake from clarifier containing 35 percent solids ($CaSO_3$ and Na_2SO_4) and 65 percent water
Maintenance	This system is designed such that scaling is not a problem. Corrosion problems can be minimized with proper system design.
Development status	Operational systems 3 Mw; 2 % S coal; 90 % SO_2 removal 94 % availability; operating since 1/75 57 Mw; 3.2 % S coal; 90 % SO_2 removal 100 % availability; operating since 10/75 Systems in engineering design and construction phase of development 95 Mw; 3.2 % S coal; startup slated for 1977 93 Mw; 3.2 % S coal; startup slated for 1978

[a]Does not include the fly ash that would be removed.

storage tank. A schematic diagram of the Wellman-Lord SO_2 recovery process is presented in Figure 7.[15] Table 8 presents pertinent design and operating data for the Wellman-Lord SO_2 recovery process.

By-Product Utilization and Disposal

Scrubbing systems for SO_2 control produce either sludges or sulfur based by-products that must be utilized or disposed. The utilization and disposal of sludges produced by lime and limestone scrubbing are emphasized in the following discussion, but waste streams from other processes are also considered. Regenerative SO_2 control systems produce by-products, sulfur, sulfur dioxide or sulfuric acid that may be sold at varying prices depending on available markets and the transportation costs. Liquid SO_2 has the highest unit value and its marketing would therefore be least affected by transport costs.

Sludges produced by lime and limestone SO_2 scrubbing systems contain primarily calcium sulfite, calcium sulfate, calcium carbonate and fly ash. Trace metals resulting primarily from coal ash components are also present in the sludge. Water content is typically 50 to 80 percent. An environmentally acceptable method for sludge disposal or utilization must be considered in the evaluation of the technical feasibility and cost of scrubbing. Numerous options have been proposed for sludge utilization[18,19] but significant application of these techniques appears to be unlikely. A recent EPA sponsored study concluded that ponding and landfill are the only near term alternatives for sludge disposal.[20]

In order to assess this problem it is useful to compare the properties of scrubber sludge to fly ash. First, sludge tends to be more difficult to dewater either by settling or filtration and rewaters more easily. The platelet-like crystal structure of calcium sulfite hemihydrate ($CaSO_3$-1/2 H_2O) is believed to be primarily responsible for the high moisture retention.[21] Depending on the sludge composition including

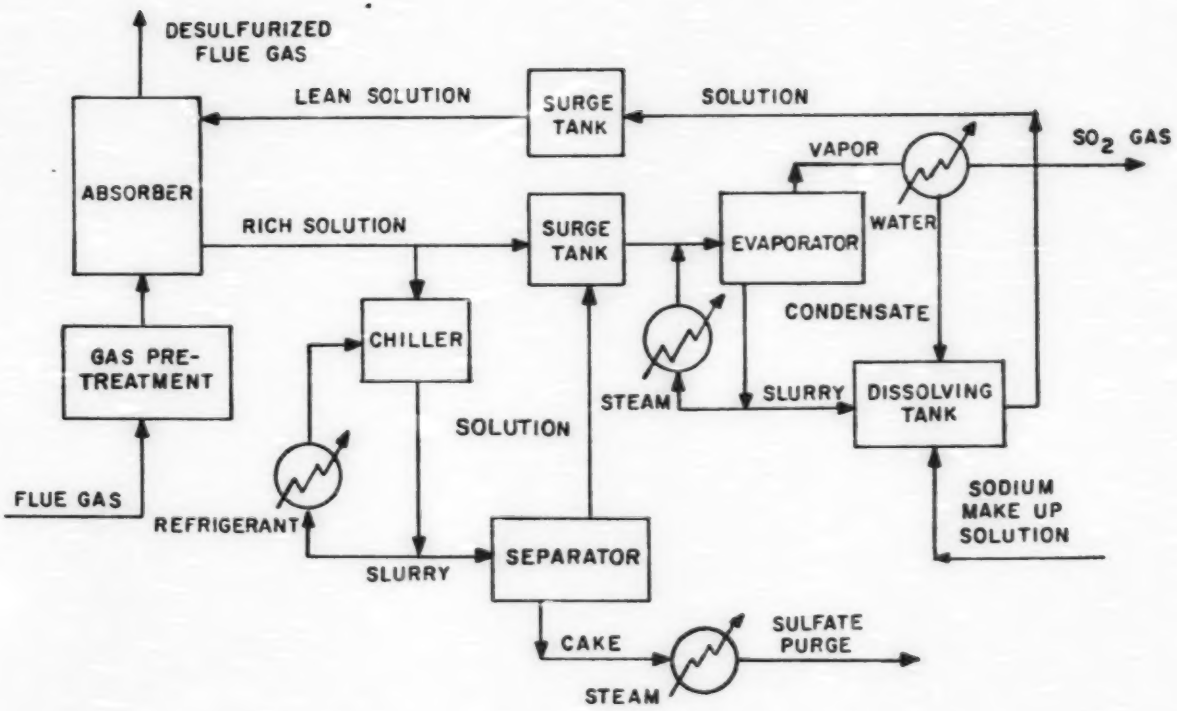


Figure 7. Wellman-Lord SO_2 recovery process[15]

Table 8. WELLMAN-LORD SO_2 RECOVERY PROCESS [27]

Smallest system capacity commercially available (scfm)	
Overall pressure drop through system (in H_2O)	30 - 40
Turndown	2:1
SO_2 removal efficiency, percent	90 - 99
Raw materials	Sodium hydroxide
By-products	Concentrated SO_2 which may be liquefied or converted to either elemental sulfur or sulfuric acid
Wastes[a] lb waste/lb SO_2 removal	0.5 lb sludge cake containing 35 percent solids (Na_2SO_4) and 65 percent water.
Maintenance	This system is designed such that scaling is not a problem. Corrosion problems can be minimized with proper system design.
Development status	System undergoing startup 115 Mw; 3.2 - 3.5 % S coal Systems under construction 375 Mw; 0.8 % S coal 340 Mw; 0.8 % S coal 500 Mw; 0.8 % S coal 500 Mw; 0.8 % S coal

[a]Does not include fly ash that would be removed.

the amount of fly ash it will settle to 30 to 65 percent solids compared to fly ash which settles to 80 percent solids. Dewatering problems lead to increased processing costs, larger ponding areas and poorer landfill characteristics. Untreated sludge liquors have a lower pH than fly ash liquors thus causing greater trace metal solubility.[22] Wet scrubbing may also collect gaseous trace elements including chlorine and mercury, increasing the water pollution potential.

Many of the utilization alternatives would have to compete with fly ash. The limitation of these markets is illustrated by the point that only 8 percent of utility generated fly ash is currently utilized.[23] Potential uses included cement manufacture, gypsum board manufacture, production of light weight aggregates, road base, etc. One U.S. utility has noted that it may make economic and environmental sense to oxidize the sludge to gypsum ($CaSO_4 \cdot 2H_2O$) even if the material has no current market value.[24] This material would be more easily dewatered, is not water soluble, and could be effectively compacted and landfilled. If market conditions improved, the gypsum could be recovered years later. For most of the potential applications sludge dewatering would be a problem. In addition, if sludge were utilized in a high temperature process such as cement manufacture, sulfur recovery would be required. Currently, lime/limestone scrubber sludges are either ponded or landfilled.

Ponding is currently the most commonly used lime/limestone sludge disposal method. All wet scrubbing systems present the potential problem of direct waste water discharge to surface waters. Eight full scale systems representing over 1500 Mw of boiler capacity have eliminated this problem by recirculating the scrubber liquor: i.e., closed loop operation.[25] Other installations recirculate as much of the liquor as technically feasible. Pollution of ground and surface waters from leachate formation is also a potential problem. Ponds may be lined with clay or synthetic materials like asphalt, PVC, Hypalon, etc.[26] The necessity for lining and/or stabilization depends on local regulations, sludge

characteristics and local geology and hydrology. Currently, only Commonwealth Edison, Will County No. 1, is using a lined (clay) pond[7] but future requirements will probably be more stringent.

Costs for sludge disposal by ponding can vary very widely, depending on land cost; the type of liner used, if any; location of the pond in relation to the scrubbers; and the settling characteristics of the sludge. The need for a pond liner and the type used and therefore the disposal cost will depend on local geology, hydrology and environmental regulations. It has been suggested that the small size of some industrial boilers may reduce the sludge disposal problem as local environmental impacts will be reduced.[27] Aerospace Corporation has conducted a detailed evaluation of ponding[26] and is currently continuing programs in the area. Data from this initial study have been updated and cost ranges are $0.2 to $3.0 per ton of sludge (50 percent solids) for unlined pond disposal and $0.5 to $10.0 per ton of sludge for lined pond disposal.[20] The large range and higher upper limits reflect uncertainty in regard to unusual local situations. A cost of $3 per ton for sludge disposal in a lined pond was reported to be typical. Costs would be nearer $1 per ton if disposal in an unlined pond is allowed. Typical truck hauling rates for stabilized fly ash for a distance of 5 miles are reported to be $0.75/ton.[20] This may represent an added cost when offsite ponding or landfill is required. Based on the above data, GCA used a cost of $4/ton for sludge disposal.

Landfill is also a viable disposal method although use of this option is currently limited. Dewatering and sludge stabilization or chemical fixation are usually required for landfills. Chemical fixation and landfilling is reported to cost more than ponding in most situations, averaging about twice as much. A specific example of chemical fixation and landfill is the Bruce Mansfield No. 1 unit, a 835 Mw system. Projected costs are reported to be $7/ton of sludge including Dravo chemical fixation, acquisition and development of considerable land, and an 8-mile

pipeline operation.[26] Fly ash and lime may be used to improve sludge quality. At Paddy's Run No. 6, 60 to 100 lb lime per ton dry solids are used to stabilize the sludge for trucking and offsite disposal.[7] Sludge from Will County No. 1 is stabilized by adding 200 lb lime and 400 lb fly ash per ton of dry solids.[7] A small industrial boiler might, depending on the local situation, be able to dispose of dewatered sludge cheaply in city or county operated sanitary landfills.

Sludge from sodium-based double alkali systems have been less intensively investigated. A major difference between sludges from lime/limestone systems and double alkali systems is that the former are primarily calcium sulfate ($CaSO_4$) while the latter are primarily calcium sulfite ($CaSO_3$). One might expect, in view of the dewatering problems attributed to minor amounts of $CaSO_3$ in lime/limestone sludge, that double alkali sludge would be difficult to dewater. However, FMC has investigated vacuum filtration and landfilling of double alkali sludge and reports success in both areas.[13] Perhaps the different conditions under which the sludges form also affects the properties.

While sludge disposal is an important environmental consideration , disposal methods are available and the annual cost should be relatively small, less than 10 percent of the total annual FGD cost.

LOW SULFUR COAL AND OTHER SO_2 EMISSION REDUCTION ALTERNATIVES

The use of low sulfur coal and/or mechanical coal cleaning are potential methods for complying with the proposed SO_2 regulations. These options will be particularly attractive in counties with the least stringent emission limitations. Coal gasification, coal liquefaction and fluidized bed combustion also appear to be applicable to industrial boilers, but will not be available until the 1980's. Therefore, these last three control methods cannot be considered for boilers in the present study, all of which must comply with the proposed regulation no later than 3 years after promulgation.

The sulfur content of coal needed to comply with the proposed regulations varies as the emission limit varies from 0.6 lb $SO_2/10^6$ Btu to 6.8 lbs $SO_2/10^6$ Btu in those counties that are regulated. Therefore, the sulfur content of "low sulfur" or compliance coal needed to comply with the proposed regulations will vary as shown in Table 9, assuming a heating value of 12,000 Btu/lb. The sulfur content of these compliance coals is higher than the 1 percent level defined as low sulfur coal in many studies. Large quantities of coal with sulfur contents in the required ranges are used by the industrial sector in Ohio. Coal shipments to Ohio industry, not including electric utilities and coke and gas plants, in 1972 totaled 12,700,000 tons of which 11 percent contained 1.1 to 1.3 percent sulfur, 6 percent contained 1.4 to 1.8 percent sulfur, 35 percent contained 1.9 to 3.0 percent sulfur and the remaining 48 percent contained above 3 percent sulfur.[28]

Coal supply district 4 (all of Ohio) provides 53 percent of industrial coal consumed in Ohio while district 8 (southern West Virginia, parts of Virginia, eastern Kentucky and northern Tennessee) provides 40 percent.[29] This industrial coal supply pattern is different from Ohio utility coal supply which consists of 64 percent district 4 coal, and only 15 percent district 8 coal. Therefore, it is evident that supply and transport routes from district 8 are available to and utilized by Ohio industry. This is important because district 8 coal is commonly low in sulfur content and reserves of compliance coal are very large.

The reserve base of mineable coal in West Virginia, Kentucky and Ohio is presented [illegible]ble 10. These listed reserves include only measured and ind[illegible]d coal seems greater than 28 inches thick and less than 1000 ft d[illegible]p for deep mining and with less than 120 feet of overburden for strip mining. Reserves within these three states are large when compared to the 66 million tons/year currently used by all Ohio consumers. Perspective on the amount of reserves may also be gained by comparison of the current U.S. consumption of about 600 million

Table 9. SO_2 EMISSION LIMITATIONS AND EQUIVALENT PERCENT SULFUR IN COAL[a]

lb $SO_2/10^6$ Btu	Percent sulfur in coal
0.6	0.36
1.0	0.60
1.5	0.90
2.0	1.2
2.5	1.5
3.0	1.8
4.0	2.4
5.0	3.0
6.0	3.6
6.8	4.1

[a]Based on a heating value of 12,000 Btu/lb and 100 percent conversion of fuel sulfur to SO_2.

tons/year to the West Virginia reserves of 40,000 million tons/total and 18,400 million tons of less than 1.5 percent sulfur coal. Even Ohio has significant reserves of coal that would comply with many of the regulations. A shift in consumption patterns by Ohio industry which uses about 12 million tons of coal per year should not affect coal supply and prices. However, a change in consumption patterns by Ohio utilities and neighboring states may affect coal prices. There may be delays in opening new mines and if demand for compliance coal out-paces the increase in supply, prices will certainly increase. These complicating factors make the prediction of future prices very uncertain.

Many Ohio industrial facilities obtain coal by spot purchases. Prices for spot purchases, FOB mine, as reported in Coal Week during 1975 indicate that district 8 coal with a sulfur content of 1.25 percent was less expensive than Ohio coal with an average sulfur content of 3.2 percent. In December 1975 Ohio spot purchased coal was $17.5/ton and district 8 coal was $14.25/ton.[31] In his testimony at the January 8, 1976 public hearing, A. L. Susman, Chairman, Mines and Mining Subcommittee, West Virgina Senate, reported several indications of a lack of

Table 10. BITUMINOUS COAL RESERVE BASE FOR SELECTED STATES, THICKNESS, TYPE OF MINING, AND SULFUR RANGE — JANUARY 1, 1974 (MILLION SHORT TONS)[30]

	RESERVES BY SULFUR RANGE, PERCENT											
Thickness	≤ 0.4	0.5 - 0.6	0.7 - 0.8	0.9 - 1.0	1.1 - 1.4	1.5 - 1.8	1.9 - 2.2	2.3 - 2.6	2.7 - 3.0	> 3.0	Unknown	Total
West Virginia												
Deep > 28	229.19	2923.45	4948.83	2985.13	3696.23	2615.11	2435.13	2057.71	1779.23	6552.88	4142.92	34377.77
Strip > 28	44.12	799.33	1363.37	798.64	581.16	262.61	239.14	191.94	147.97	270.40	509.55	5212.02
Total	273.31	3722.78	6312.20	3783.77	4277.39	2877.72	2674.27	2249.65	1927.20	6823.28	4652.47	39589.79
Kentucky												
Deep > 24	0.00	0.00	0.00	0.00	0.00	0.39	1.19	70.44	314.56	7226.36	1107.11	8719.89
Strip > 24	0.00	0.00	0.00	0.22	0.83	8.53	22.22	45.20	101.05	2017.45	1708.79	3904.02
Total	0.00	0.00	0.00	0.22	0.83	8.92	23.41	115.64	415.61	9243.81	2815.90	12623.91
Ohio												
Deep > 28	0.00	9.09	37.49	68.87	318.26	693.25	954.59	1414.95	2068.83	10109.36	1754.09	17423.26
Strip > 28	0.00	2.97	5.27	10.63	41.55	93.05	192.70	310.27	353.39	2524.87	117.93	3653.89
Total	0.00	12.06	42.76	79.50	359.81	786.30	1147.29	1725.22	2422.22	12634.23	1872.02	21077.15

demand for low sulfur coal and significant idle mines capable of producing less than 1 percent sulfur coal.[32] When switching from one coal to another, many coal properties including ash composition, ash fusion temperature, moisture content, etc. can affect boiler performance.[33,34] A siitable coal supply can only be determined on a case-by-case basis due to variations in the regulations and required fuel specifications. For the sites visited in this study GCA telephoned suppliers to determine current prices for coal with the required sulfur contents.

Mechanical coal cleaning has been widely used for many years and in 1973 about 50 percent of total coal consumption was cleaned coal.[35] Many of the systems now in operation, however, were designed primarily for ash removal. All coal used for coking (17 percent of total coal consumed and 33 of cleaned coal consumption) is cleaned to reduce both the sulfur and ash content. Coal cleaning technology is clearly commercially proven but its effectiveness depends on the properties of the specific coal being cleaned. A summary of the application of mechanical coal cleaning in 1973 is presented in Table 11. Most West Virginia coal is cleaned but much greater sulfur reduction could probably be achieved through process improvements. On the other hand, less than half of Ohio coal production is cleaned and increased application of coal cleaning as well as improvement of existing systems could greatly reduce the sulfur and ash content.

Mechanical coal cleaning separates coal constituents with different specific gravities, as shown in Table 12. Sulfur is present in coal both as pyritic sulfur, which can be separated, and organically bound sulfur which cannot be mechanically removed. The pyritic sulfur composes 20 to 80 percent of the total sulfur with the lower percentage usually found in lower sulfur coals.[22] Analysis of Ohio coals indicates that a about half the sulfur is present as organic sulfur.[36] Crushing frees the pyritic sulfur particles from other coal particles and is the first step in mechanical cleaning. Coal is commonly crushed to less than

Table 11. MECHANICAL CLEANING AT BITUMINOUS COAL AND LIGNITE MINES, IN 1973, BY STATE (THOUSAND SHORT TONS)[35]

State	Total production	Mechanical cleaning			
		Number of cleaning plants	Raw coal	Cleaned coal	Refuse
Alabama	19,230	19	18,433	11,705	6,728
Alaska	694	1	70	50	20
Colorado	6,233	3	1,933	1,662	270
Illinois	61,572	36	62,386	48,091	14,295
Indiana	25,253	10	25,330	19,699	5,631
Kentucky:					
Eastern	73,966	33	30,359	22,264	8,095
Western	53,679	18	26,004	20,005	5,999
Total	127,645	51	56,363	42,269	14,094
Ohio	45,783	17	20,799	14,588	6,211
Oklahoma	2,183	3	381	312	69
Pennsylvania	76,403	68	63,041	45,731	17,310
Tennessee	8,219	2	1,575	1,145	430
Utah	5,500	7	4,156	3,375	581
Virginia	33,961	32	26,559	17,696	8,863
Washington	3,270	2	4,460	3,262	1,198
West Virginia	115,448	124	107,320	75,672	31,848
Other States[a]	60,344	7	4,639	3,460	1,179
Grand total[b]	591,738	382	397,646	288,918	108,728

[a]Includes Arizona, Arkansas, Iowa, Kansas, Maryland, Missouri, Montana (bituminous coal and lignite), New Mexico, North Dakota (lignite), and Wyoming.

[b]Data may not add to totals shown because of independent rounding.

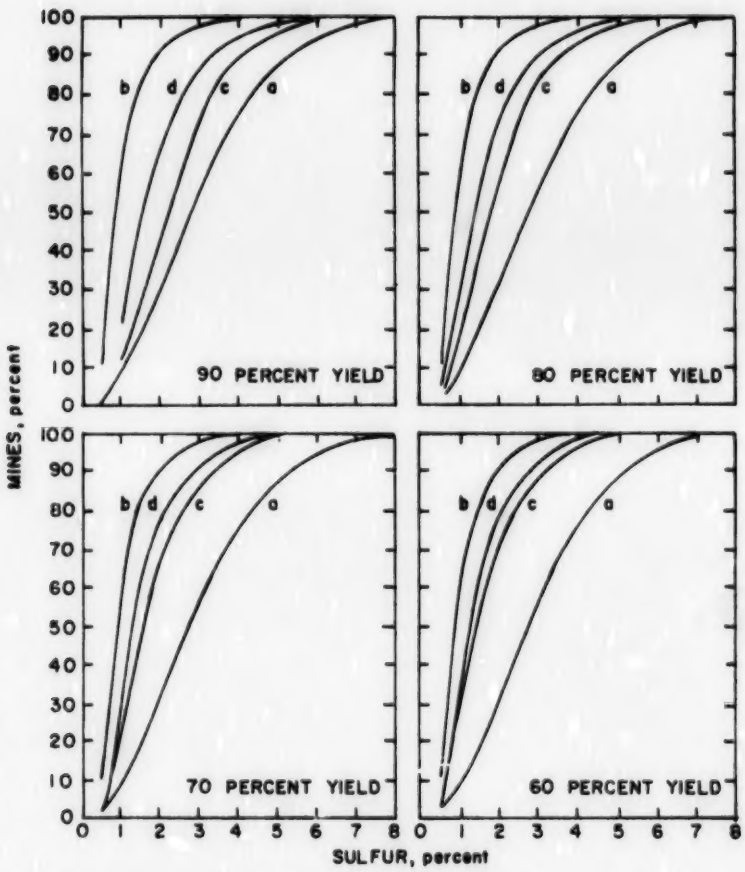
Table 12. SPECIFIC GRAVITIES OF COAL AND IMPURITIES

Material	Specific gravity
Bituminous coal	1.12 - 1.35
Bone coal	1.35 - 1.7
Carbonaceous shale	1.6 - 2.2
Shale	2.0 - 2.6
Clay	1.8 - 2.2
Pyrite	4.8 - 5.2

1-1/2 inches or less than 14 mesh and smaller in certain cases. The finer size produces better sulfur removal but the crushed coal is harder to handle and cleaning costs increase. Wet concentrating tables, compound water cyclones, air classification, froth flotation and concentrating spirals are widely used conventional commercially available methods for density separation in coal cleaning.[37] The net costs for mechanical coal cleaning are difficult to assess due to variations in coal washability. The Commerce Technical Advisory Board reported mid-1974 costs of $1.2 to $2.2/ton for crushing to 3/8 in. with single stage separation and $2.9 to $4.8/ton for a more elaborate multistage separation of finer particles.[38] Cost projections in Coal Age indicate a range of $6.5 to $9/ton to clean Appalachian coal to less than 1 percent sulfur.[39] An update by GCA of cost data reported by Battelle,[27] indicates a current coal cleaning cost of $6/ton of product for removal of pyritic sulfur for the conditions used by Battelle.

Several cost benefits must be balanced against the coal cleaning costs. Coal cleaning reduces the ash content by 60 to 70 percent, and increases the heating content. Therefore, coal transport costs and ash handling and disposal costs are reduced. Boiler operation is potentially improved by reduced slagging, reduced need for particulate control, improved boiler availability and lower boiler operating and maintenance costs.[34] The Commerce Technical Advisory Board concluded that coal cleaning with or without additional FGD were the least expensive options for utility systems to meet the new source performance standard of 1.2 lb $SO_2/10^6$ Btu.[39]

Washability studies conducted on Northern Appalachian coals (Maryland, Ohio, Pennsylvania, Northern West Virginia) showed that coals from 20 percent of the mines could be washed to less than 1 percent sulfur and coal from 65 percent of the mines could be washed to less than 2 percent sulfur at a 90 percent yield when crushed to -14 mesh.[37] These results are summarized in Figure 8. The washed coals discussed above contained only 5 to 7 percent ash and had a heating value of about



(a) RAW COAL TOTAL SULFUR CONTENT CURVE;

(b) RAW COAL ORGANIC SULFUR CONTENT CURVE;

(c) WASHED COAL TOTAL SULFUR CONTENT COAL CURVE WHEN RAW COAL WAS CRUSHED TO MINUS 1 1/2 INCHES; AND,

(d) WHEN RAW COAL WAS CRUSHED TO MINUS 14 MESH.

SOURCE: REFERENCE 37

Figure 8. Washability of northern Appalachian region coals

13,000 Btu/lb.[37] Coals from the Northern Appalachian region are used extensively in Ohio. Washability studies were also conducted on Southern Appalachian coals, roughly equivalent to coal supply district 8, showing that samples from 90 percent of the mines could be reduced to less than 1 percent sulfur at a 90 percent yield when crushed to -14 mesh.[37]

SECTION IV

SO_2 EMISSION REDUCTION COSTS

To obtain accurate control equipment costs, GCA asked four flue gas desulfurization system manufacturers to submit budgetary cost quotations. Pertinent boiler design and operating data along with site layout diagrams were included in GCA's request for cost estimates. Combustion Engineering, Davy Powergas, Research-Cottrell and FMC were the four flue gas desulfurization system manufacturers that were contacted. Combustion Engineering informed us that they did not manufacture systems as small as the one we were considering. Based on previous cost estimates for larger systems obtained from Davy Powergas it appears that their desulfurization system is not economically attractive in the small size range considered for Mead. FMC could not provide us with cost estimates within the time frame of this project. However, Research-Cottrell did cooperate by submitting a budgetary cost quotation. The desulfurization system was sized such that it could handle 114,000 scfm of the 334,000 scfm of stack gas and give an overall SO_2 reduction of 30 percent. Operating costs were based on a 70 percent yearly load.

Based on the cost estimates received from Research-Cottrell, we estimate the average annual control costs to be $\$0.220/10^6$ Btu. In addition to flue gas desulfurization, blending the coal presently used with low sulfur coal was also considered as an SO_2 emission reduction alternative. We estimate the additional annual fuel coal cost plus the average annual cost of a blending facility to range from \$0.225 to $\$0.280/10^6$ Btu. Mechanical coal cleaning is potentially the least expensive option at $\$0.08$ to $\$0.15/10^6$ Btu. This third option could probably not be implemented by Mead alone but could be implemented by a large mining company.

One should not base the selection of SO_2 emission reduction alternative solely on cost. When considering flue gas desulfurization, the demonstrated performance and reliability, the tkpe of guarantee and various site-specific considerations such as raw materials, utilities and solid waste disposal requirements must also be taken into a ccount. Similiarly if blending low sulfur coal is chosen as an SO_2 reduction technique, long-term contracts with fuel suppliers, price stability, and guaranteed supply become important considerations.

FLUE GAS DESULFURIZATION

Utility, Material and Labor Requirements for Flue Gas Desulfurization Systems

Detailed utility, material and labor requirements based primarily on data furnished by Research-Cottrell are presented in Table 13 for the 114,000 scfm flue gas desulfurization system considered for Mead. This table includes the power requirements of the fans and pumps, and the process water and lime required for absorber solution makeup. Since flue gas reheat for this case can be easily accomplished via bypass, steam is not required. We have assumed that both the labor and the material required to maintain the desulfurization system to each have an annual cost of 3.5 percent of the fixed capital investment based on a TVA study.[40] Maintenance costs used in this study are on the high side of the probable range. Research-Cottrell based on operating experience at CHOLLA, reports that costs for their systems should be less than half those used in this study. We estimate 0.5 men per shift will be required to operate the desulfurization system based on Batelle study.[27] These requirements are more conservative than Research-Cottrell's estimates of 0.25 men/shift.

Utility, Material and Labor Costs

Table 14 presents detailed utility, material and labor costs derived from the requirements noted in Table 13.

Table 13. UTILITY, MATERIAL AND LABOR REQUIREMENTS FOR FLUE GAS DESULFURIZATION AT MEAD BASED ON MAXIMUM RATED CAPACITY[8]

	Bahco Lime, Research-Cottrell
Utility	
Power, kwh/day	20,820
Process water, 1000 gal/day	75
Material	
Lime (CaO), tons/day	27.9
Maintenance, percent of fixed capital investment per year	3.5
Labor	
Operation, men/shift	0.5
Maintenance, percent of fixed capital investment per year	3.5

Table 14. UTILITY, MATERIAL AND LABOR COSTS FOR FLUE GAS DESULFURIZATION AT MEAD BASED ON MAXIMUM RATED CAPACITY AND A 70 PERCENT YEARLY LOAD FACTOR, 10^3/yr

	Bahco Lime, Research-Cottrell
Utility	
Power, $0.02/kwhr	106
Process water $0.20/1000 gal	14
Total utilities	110
Material	
Lime (CaO), $40/ton	285
Maintenance	148
Total material	433
Labor	
Operation, $8/man-hour	35
Maintenance	148
Total labor	183
Total utility, material and labor	726

Capital and Annualized Cost

The capital and annualized cost as well as the individual components used to formulate these costs are presented in Table 15. These costs are current to June 1976. The most important cost component, the installed cost of the battery limit plant, was based on an up-to-date quotation furnished by Research-Cottrell.[8] Other costs were obtained from Table 14 and an accounting technique derived from the Utility Financing Method as Modified by the Panhandle Eastern Pipeline Company.[27]

The cost of retrofit was estimated to be 10 percent of the average capital cost of the installed battery limit plant for Mead.[14] As discussed in an earlier section, solid waste disposal costs were estimated to be approximately $4/ton. We found that flue gas desulfurization cost $0.214/$10^6$ Btu for this 114,000 scfm system.

COST OF COMPLIANCE COAL

Low Sulfur Coal

Since the coal-fired boilers operating at Mead are pulberized dry bottom units, the fusion temperature of low sulfur coal is not important. At the present time Mead is burning 246,000 tons per year of coal containing 4.3 percent sulfur and having an average heating value of 11,546 Btu/lb.

They are paying the very low price of $16.5/ton delivered. In order to comply with the proposed SO_2 regulations, Mead must burn coal with a sulfur content less than 3 percent.* Because of the low price of the coal presently being burned, economic favor blending this coal with low sulfur coal as a means of obtainging 3 percent sulfur. Island Creek, Pittston and Princess Coal Companies all have low sulfur coals that are suitable for blending with Mead's present coal.[42-46] The fact that these coals are

*Based on a heating value of 11,546 Btu/lb.

Table 15. CAPITAL AND ANNUAL COSTS OF 114,000 scfm FLUE GAS DESULFURIZATION SYSTEM AT MEAD CORPORATION, 10^3, JUNE 1976[8,41]

	Bahco Lime, Research-Cottrell
Capital requirement	
Battery Limits Plant installed (BLP)	3,250[a]
Site preparation and utilities, 20% of BLP[b]	650
Additional retrofit requirements	325
Fixed capital requirements	4,225
Working capital,[c] 20% of gross operating cost	218
Total capital requirement	4,443
Annual operating cost	
Labor[d]	183
Administrative and general overhead,[c] 60% of labor	110
Utilities[d]	110
Materials[d]	433
Local taxes and insurance,[c] 2.7% of fixed capital requirement	114
Solid waste disposal, $4/ton	142
Gross operating cost	1,092
Sulfur dioxide byproduct,[e] credit $110/ton	0
Total annual operating cost	1,092
Annualized cost	
Annualized capital cost[f]	453
Federal income tax[e,g]	81
Total annual operating cost	1,092
Average annual cost	1,626
Average annual control cost, $/lb S removed	0.195
$/10^6 Btu input	0.220[h]

[a] Manufacturer's estimate, June 1976

[b] Normal site preparation; cost to bring utilities to the battery limit plant and connect raw flue gas ducts to BLP based on GCA review of similiar costs reported in literature.

[c] Based on Utility Financing Method as modified by the Panhandle Eastern Pipeline Company and described in Reference 27.

[d] See Table 13.

[e] Based on cost data presented in Reference 15.

[f] Total capital requirement is amortized over 20 years at a discount cash flow rate of 8 percent. This works out to an effective rate of 10.185 percent per year of the total capital requirement.

[g] Average Federal Income Tax = 1.731 percent of the sum of the total capital requirement and working capital.

[h] This value is low because only about 35 percent (114,000 scfm) of the stack gas flow from the boiler will need to be desulfurized in order to meet the proposed SO_2 emission limitations.

from Virginia and West Virginia coupled with Mead being located in the southeastern corner of ohio facilitates delivery by truck, thus eliminating the need for construction of a rail unloading facility. These coals have sulfur contents in the 0.7 to 1.2 percent range and have delivered costs of $1.23 to $1.42 per 10^6 Btu[42-46] as outlined in Table 16. To comply with the proposed regulation of 5.2 lb $SO_2/10^6$ Btu, 36 to 41 percent of the coal burned at Mead would need to be low sulfur coal, see Table 16. The increase in fuel cost would amount to $1.1 to 1.4 million per year.

Mead has estimated that a coal blending facility would require a capital investment of $900,000. Annualized cost for this capital investment, including federal income tax, local taxes and insurance, annualized capital costs, maintenance and utilities would be $154,000 based on the methods previously discussed in Tables 3 through 5. Therefore, the total increase in annual costs to comply with the proposed regulation by burning a blended compliance coal would be $1.28 to $1.59 million per year or $.225 to $.280/$10^6$.

Mechanically Cleaned Coal

Mead Paper Company obtains coal from Vinton and Jackson Counties at a cost of $16/ton delivered. Average sulfur content is 4.28 percent and the heating value is 11,500 Btu/lb. If this coal was mechanically cleaned to a sulfur content of 3.4 percent and a heating value of 12,500 Btu/lb then it would comply with the proposed regulation of 5.2 lb $SO_2/10^6$ Btu. Alternatively the coal might be cleaned to a lower sulfur content and blended with uncleaned coal to meet the proposed regulation.

Data on the washability of Jackson County coal are presented in Table 17.[36] This table indicates that a large percentage of the sulfur in Jackson County coal is pyritic sulfur and it is easily cleaned to the levels needed to comply with the proposed regulation. It appears that a simple coal cleaning plant discussed by the Commerce Technical Advisory Board[38]

Table 16. COST AND SULFUR CONTENT OF PERCENT COAL AND BLENDED COMPLIANCE COALS

Coal company	Coal source	Percent S	lb S 10^6 Btu	Coal cost $/10^6 Btu	Btu/year required		Total cost $/$10^6$ Btu	Increase in fuel cost $10^6/yr	SO_2 Emissions lb/10^6 Btu
					Low S coal 10^{12} Btu/yr	Present coal 10^{12} Btu/yr			
Island Creek	W. Va.	0.80	0.64	1.320	2.065	3.614	5.318	1.25[a]	5.2
	-	0.70	0.57	1.423	2.020	3.660	5.499	1.44[a]	5.2
Pittston	Va.	1.2	1.0	1.250	2.340	3.340	5.319	1.26[a]	5.2
Princess	W. Va.	<1.0	<0.81	1.230	<2.186	<3.494	<5.194	<1.13[a]	5.2
Present coal	Ohio	4.3	3.74	0.717	-	5.68	4.06	-	7.48

[a]Coal blending facility could cost an additional $154,000 per year based on capital investment of $900,000 and the accounting method used in Tables 3 to 5.

Table 17. SULFUR CONTENT OF CLEANED JACKSON COUNTY COAL[a]

Yield, percent	Crushed Coal 1-1/2 inch	3/8 inch	Size 14 mesh
80	2.73	2.51	2.52
90	3.17	2.87	2.73

[a]Reference 36. The total sulfur content of the uncleaned coal was 4.03 percent with 1.9 percent pyritic sulfur.

involving crushing to 3/8 inch, single stage separation and 80 percent recovery would produce a coal with a sulfur content well below the maximum allowable. Mid 1974 capital costs for a 1,000,000 ton/year facility were $4,350,000.[38] Operating costs including labor, maintenance and power were estimated to be $0.3 to $0.6/ton of clean coal and the total cost differential of the clean coal product was $1.4 to $2.2/ton.[38] The Marshall and Stevens equipment cost index has increased almost 25 percent from mid-1974 to mid-1976. A reasonable cost for mid-1976 would therefore be $2 to $3/ton. A smaller plant size would be more appropriate for Jackson County as only 1,000,000 tons of coal were produced in 1973.[35] Therefore, unit costs would be slightly higher and probable clean coal cost would be $2 to $4/ton above the cost of uncleaned coal. Because the clean coal would have a heating content of 13,000 Btu/lb the incremental cost would be $0.8 to $0.15/$10^6$ Btu of clean coal. Mechanical coal cleaning would have to be implemented by owners of a large mine and would depend on the marketability of clean coal to other consumers in addition to Mead.

Mead would obtain additional benefits from using clean coal that would tend to further lower the cost. Coal cleaning would reduce coal transport, handling and pulverization costs. In addition ash collection, ash disposal and boiler maintenance costs might be reduced.

SECTION V

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